Staff Report On:

POWER PLANT AND TRANSMISSION LINE TRENDS UNDER RESTRUCTURING

Prepared for the July 16, 17 & 18 1996 **ER 96** Committee Hearing
on Issue I.C.1.

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State of California

June 18, 1996

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EXECUTIVE SUMMARY

Power plants and transmission lines in California were historically constructed and operated by the investor-owned utilities (IOU) and municipal utilities (munis). Through their planning activities, these utilities identified the needs of the customers in their service areas and constructed energy facilities as appropriate to respond to those needs. In resource plans prepared during the late 1970s and early 1980s, the utilities were able to not only accurately characterize their existing generation and transmission systems but were able to identify when and where new power plants and transmission lines would be built. The Energy Commission and other state and local agencies were able to use this information to develop trends which indicated the type, number and location of projects to be permitted and issues to be addressed during permitting or in planning activities.

In an effort to understand the direction of future energy facilities and permitting issues in California, the **1996 Electricity Report** (ER 96) Committee, in their February 15, 1996 Order, requested the parties address: "likely trends in new powerplants and transmission lines under restructuring" (Issue I.C.1.). In attempting to respond to the Order, we initially interviewed several power plant developers and surveyed the literature to determine if there were any clear trends regarding the development of energy facilities that would provide electricity to California. The result of these interviews revealed tremendous uncertainty, particularly on the timing of new energy facilities. This uncertainty was primarily the result of decisions pending before the California Public Utilities Commission (CPUC) and Federal Energy Regulatory Commission (FERC) on restructuring.

Over the next year, the CPUC and FERC will be making key decisions relating to electric industry restructuring. Decisions relating to utility power plant divestiture, the size of the competitive transition charge (CTC), who must pay the CTC, who will be able to avoid the CTC, direct access and many others will have a significant bearing on the future direction and outcome of electric industry restructuring.

In Peter Schwartz's book, The Art of the Long View, Planning for the Future in an Uncertain World, scenarios are identified as a tool for helping one take a long view in a world of great change and uncertainty. Scenarios are stories about the way the world might turn out in the future, stories that can help us recognize and adapt to these changes. They form a method for describing the different pathways that might exist tomorrow and finding the appropriate responses. Scenario planning is about making choices today with an understanding of how they might turn out in the future.[1]

Due to the uncertainty facing the electric industry, we assembled a multi-divisional team from the Energy Forecasting and Resource Assessment Division, Energy Technology Development Division and Energy Facilities Siting and Environmental Protection Division to develop and assess possible scenarios of the future. Team members were selected based on their expertise in economics, today's regulatory climate, transmission system planning, generation system planning, electric supply and demand forecasting, environment protection, project permitting, project finance and new technologies. Additionally, we interviewed industry consultants, project finance specialists, bankers and various utility representatives to gain further insights.

In developing the scenarios the team reviewed and analyzed a good deal of information and data from many sources and disciplines. From this information and the expertise of the respective members of the team, we identified the key driving forces and then isolated a single driving force in each scenario. Each driving force became the theme of a separate energy facility scenario. Table 1 summarizes the power plant siting implications and the driving forces or theme behind each scenario.

We also analyzed a number of issues to help determine the energy facilities likely to be proposed in California and the issues likely to be faced during permitting. This included:

- future electric generation sites,
- repowering opportunities,
- future transmission lines and corridors,
- facility closures
- project finance issues
- new technologies
- key environmental and permitting barriers.

The team developed six scenarios or stories regarding future power plant and transmission facility trends and some of the key uncertainties associated with electric industry restructuring. They are very preliminary and represent an initial cut at the widely varying but possible outcomes of energy facility development under restructuring.[2] **In presenting this analysis, we are not advocating any scenario nor do we feel they are the only scenarios possible. They were developed to provide a possible indication of the energy facilities and issues that may arise in the future and to determine if this form of analysis will be valuable.** However, we believe that it is a start towards defining the problem and establishing ranges, not necessarily boundaries, on the **ER-96** Committees request to identify the likely trends in the type, size and amount of new electric generation and transmission under restructuring. These stories help us to anticipate changes and to be prepared to respond to a wide range of future issues and events which, if unanticipated, could adversely affect the efficient and timely permitting of energy facilities for California.

We developed two scenarios for the five-year planning period 1996 through the year 2000. Scenario #1--Early Market Positioning is assumed to induce 4-5 new plants and 2-3 repowers during the next several years, whereas, Scenario #2--Regulatory Uncertainty, assumes few, if any, new power plants or transmission lines.

For the six to twelve-year planning period (2001 to 2007), we developed four scenarios. Scenario #3--Repowering, is assumed to induce up to 2,000-3,000 MW of new generation through repowering of existing facilities. Scenario #4--Distributed Generation, envisions hundreds of substation-, neighborhood-, commercial- and industrial-sized generation sources along with thousands of home appliance-sized units which could provide up to 10% of total statewide electricity demand (about 6,500 MW) ranging in size from 5 MW down to 4 kWh. Scenario #5--Unleashed Entrepreneurial Spirit, assumes 5,000+ megawatts of new generation, while Scenario #6--The Market Blossoms, assumes 11,000+ megawatts of new in-state, new out-of-state and repowered generation to meet load growth and replace San Onfre Nuclear Generation Station (SONGS).

Table 1--Facility Implications and Driving Forces Behind Each Scenario

1996-2000	**Facility Implications**	**Driving Forces**
Scenario 1-- Market Positioning	4-5 new plants and 2-3 repowers proposed	Private businesses successfully enter the generation market
Scenario 2 -- Uncertainty	fewer than scenario #1	Regulatory uncertainty and capacity over-supply
2001-2007		
Scenario 3-- Repowering	2-3,000 MW repowers	Utilities attempt to retain market shares and market power
Scenario 4-- Distributed Generation	6,500 MW distributed generation	New technologies
Scenario 5-- CTC Escape	5,000+ MW new generation	Competitive markets emerge
Scenario 6-- Market Blossoms	11,000+ MW new generation	CTC is fixed charge, low energy costs induce economic expansion

There are two main points to be made with respect to trends in the location, size and type of new generation facilities and transmission lines under restructuring:

1. **The future is very uncertain.** Decisions currently being debated by the CPUC, the FERC and the legislature will have major ramifications for the utility industry, project developers, utility stockholders, ratepayers and the citizens of California. To predict, today, what these many separate, yet highly linked, decisions will be and to further predict their effect on the electric generation and transmission system, project developers and the citizens of California, is not possible with any degree of certainty. The very uncertain future is reinforced by the wide range of plausible futures analyzed in the six scenarios from few, if any, new plants in the near future to 11,000 MW over the next twelve years.

   Environmental issues that will be raised in association with the siting of future energy facilities are also uncertain. Because restructuring is not entirely defined, it is unclear how restructuring will effect existing air quality regulations, particulate matter regulations and the availability of air offsets, and conversely, how air quality regulations may facilitate or impede new or repowered generation facilities. Water resources, local land-use plans, toxics regulation and growth management are examples of other environmental issues that are likely to become more important for individual energy facilities and the entire electrical system as California enters the 21st century.

2. **Continued monitoring and follow-up is necessary.** As in the restructuring of any industry, given the almost experimental nature of the effort and multiplicity of decisions that must be made, there are many opportunities for errors. It will be necessary and important to provide feedback and information to the decision makers (the agency Commissioners, the Legislature and the Governor) and to make corrections as the industry and regulatory agencies move into uncharted restructuring waters. In addition to monitoring restructuring and its effects on energy facilities, the relationship between environmental issues and the energy system also needs to be closely followed.

The Energy Facilities Siting and Environmental Protection Division's Trends and Issues Program was recently created to track and identify likely future power plant and transmission trends on an ongoing basis. This work is performed by closely coordinating with other Divisions in the Energy Commission, regulatory agencies and experts in the electricity industry, financial community and environmental community. The three objectives of the Program are to:

1. access existing information sources and, as necessary, create and maintain a data base and geographic information system (GIS) of selected information in the areas of transmission and generation facility planning and operations, environmental issues and regulation, project permitting and regulatory climate, economics and project finance, and commercial technology development;

2. use the information to identify driving forces, trends and key issues affecting the development of future power plants, transmission lines and other energy facilities; and

3. develop short-term and long-term energy facility scenarios and provide the Commission recommendations on responses to these various futures.

In addition, such information is crucial for Energy Commission's energy facility licensing process if it is to provide the flexibility needed for new market entrants, while providing both the appropriate level of environmental review and procedural certainty. We recommend continuing this function.

INTRODUCTION--RESTRUCTURING AND AN UNCERTAIN FUTURE

The electric generation and transmission system in California and the western states is a highly integrated and complex network of power plants, inter-state transmission, intra-state transmission and local distribution lines. This network of generation and transmission, the electric utility industry, the regulated investor owned utilities (IOU), the municipal utilities (munis), the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) face a rapidly changing and uncertain future. The Federal Energy Regulatory Commission (FERC) has recently issued a rulemaking to promote competition through open access to electric wholesale transmission services. The CPUC is in the process of completely restructuring the industry in an effort to lower rates through increased competition at the retail level.

This restructuring will include the addition of several new business organizations placed in strategic positions within the electric generation and transmission network. An Independent System Operator (ISO) will be responsible for the operation and loading of the transmission system. The Power Exchange (PX) will act as a forward market where power will be bought and sold from a pool by many buyers and sellers. Additionally, the CPUC is encouraging SCE and PG&E to divest through a spinoff or an outright sale to a nonaffiliated entity of at least 50% of their fossil generation assets. These changes will have significant ramifications on how the current generation and distribution system will be operated, dispatched, utilized, loaded and maintained in the future.

In addition to these regulatory changes, the current generation system and transmission system may also face considerable physical changes in the future. Many generation units are rapidly approaching or have already exceeded their design life of 30-40 years. By the year 2000, approximately 18,000 MW (110 units) of existing generation in California will be at least 30 years of age; 8,000 MW will be at least 40 years old.[3] These units represent technologies that are fuel and environmentally inefficient compared with today's technologies. Many could be either sold, retired, repowered or replaced outright with new, highly efficient, environmentally sensitive technologies under a competitive market.

The existing transmission network was designed and built to move utility-owned generation to service area load centers in an efficient manner. Under restructuring, future generation sites will be selected by project proponents for many and various reasons. This may result in a less than optimum location of generation with respect to the transmission system. Because of this, the transmission and distribution system may not operate as efficiently as it has in the past and may not adequately meet the needs of new generators.

All of this points to a very uncertain future. These events will reshape the structure and form of the electric generation system, the existing utility companies (IOUs and Munis), and the entire electric industry and will spawn a whole new generation of enterprises and service providers heretofore unknown in the electric utility industry. These changes will also have a profound impact on the number, location, size and type of new power plants and transmission lines likely to be developed in the future and will also have ramifications on the way in which transmission and generation projects are financed, structured and developed in the future.

The sheer number and complexities of the uncertainties associated with restructuring make it difficult to identify the likely trends in new power plant and transmission line development. Anticipating the changes in power plant operations, the magnitude of the CTC, whether the CTC is a fixed or variable charge, the PX clearing price, future demand and rates under restructuring, bear significantly on the future and raise many issues and questions. Some, of which, are as follows:

- Which plants will be sold under a voluntary divestiture of 50% fossil generation requested of PG&E and SCE?

- Which ones will be retained by the utilities? How will these plants be operated and dispatched?

- Will the utilities repower retained plants?

- How will the new owners operate the divested plants? Will it be similar or different than the way in which the utilities have historically operated these plants?

- Will the new owners of the divested plants repower these plants?

- Will the new owner convert the property to another use other than power generation?

- Which of the remaining utility fossil plants continue to be economic when bid into the PX?

- How will PX generation bids result in changes in operating profiles of utility plants?

- Will the total delivered costs of new power plants sufficiently low to displace existing fully amortized plants?

- Will the total cost of electricity be sufficiently lower to induce economic growth?

- Will the industries that have avoided California due to high rates now be prepared to locate in California?

- What will happen to demand for electricity?

- Will the CTC be a fixed or variable charge? Will the CTC be bypassed by new customers, municipals, load growth and customers with interruptable service?

- Will there be enough regulatory certainty in the industry to obtain financing for new power plant development?

The issues and questions are seemingly endless. The CPUC and FERC decisions relating to many of these issues will have a significant bearing on the future direction and outcome of electric industry restructuring and, of course, on the plausibility of the various scenarios presented here. In the six scenarios we address many of these issues and postulate future outcomes. In Table 2, Key Restructuring Uncertainties Governing Plant Operations, New Plant Construction and Energy Consumption, we identify key restructuring uncertainties addressed in the various scenarios.

This vastly uncertain future is the context in which we present the following six scenarios.

Table 2--Key Restructuring Uncertainties Governing Plant Operations, New Plant Construction and Energy Consumption

KEY RESTRUCTURING UNCERTAINTIES	SCENARIOS					
	Near-term 1996-2000		Long-term 2001-2007			
	#1 Market Positioning	#2 Uncertainty	#3 Repowering	#4 Distributed Generation	#5 CTC Escape	#6 Market Blossoms
Operations -Existing Plants						
Divestiture	50%	50%	50%	50%	50%	100% w/ competition
Utilities retain plants with locational market power	yes	yes	yes	yes	yes	no
Repowering	few	no	yes	no	yes*	yes**
Out-of-state generation		slight increase in purchases				
Construction						
Retire Nuclear					SONGS retired	SONGS retired
Retire Fossil					some older plants closed	some older plants closed
New In-State	4-5 new plants, 2-3 repowers	few, if any, proposed	2,000-3,000 MW of repowering	6,500 MW distributed generation	5,000+ MW* new generation	11,000+ MW**
New Out-of-State					yes*	yes**
Demand						
Economic Induced	slight					yes
Rate Design	CTC variable, high rates	CTC variable, high system rates	CTC variable, high rates	CTC variable, high system rates	CTC variable, high system rates	CTC fixed, low energy costs
Fuel Switch				many DG units		
Uncommitted DSM	middle-level	middle-level	middle-level	middle-level	middle-level	declining, low-level
Other						
CTC	new loads exempt	CTC non-bypassable	CTC non-bypassable	local generation avoid CTC	new loads, municipals, & load growth avoid CTC	CTC non-bypassable
Take over Muni loads	some muni loads				some muni loads	
Start of restructuring	Jan 1998	Jan 2000	Jan 1998	Jan 1998	Jan 1998	Jan 1998
Reduce reserve margins	yes	yes	yes	yes	yes	yes

* The combined total of repowering, new in-state and new out-of-state generation equals 5,000+ MW
** The combined total of repowering, new in-state and new out-of-state generation equals 11,000+ MW

SCENARIOS FOR THE FIVE-YEAR PLANNING PERIOD: 1996-2000

The next five years will be pivotal for the electricity industry. The rules for restructuring will be determined by the CPUC, FERC and Legislature and the transition to a "competitive market" will begin in earnest. Legal challenges to the restructuring decisions are likely to materialize and the role of government in the new restructured environment will be debated.

In considering scenarios for this five-year period, we assumed that few, if any, of the pending or BRPU resources would be procured. We also assumed that reserve margins will fall below historical levels of 18-22% but will remain at or above the WSCC guideline of 7%. We are uncertain how uncommitted DSM will play out in the transition period and consequently assumed staff's middle level scenario--"Business-as-Usual"[4]. We also assumed that the utilities would divest 50% of their fossil resources as urged by the CPUC and will retain those generation units with strategic locational market power as required by the CPUC.

The two scenarios developed represent two ends of the spectrum in terms of the success of restructuring actually developing a viable, competitive environment in the short term. Scenario #1 presents a view that restructuring will be implemented successfully and on schedule; while Scenario #2 envisions that the regulatory uncertainty continues through 2000 as does the surplus supply of capacity.

Scenario #1--Early Market Positioning or "Early Bird Gets the Worm"

☛ **Driving Force/Scenario Theme:** Private Businesses Successfully Enter the Generation Market

Scenario presumptions:

- Restructuring begins on schedule--January 1, 1998
- Prices for out-of-state power gradually rise
- Economic forecasts and the growth projections are robust
- Well-financed project developers are actively planning to enter the market to get a head start on competitors
- Consortiums of large project developers, gas suppliers, construction firms and utility-plant operators are forming
- Projects are securing up-front "anchor" tenants of muni and irrigation loads, new loads and customers with interruptable service
- The scenario is assumed to induce 4-5 new power plant proposals in the 25-400 MW range (most likely gas-fired) and 2-3 repower proposals of existing facilities

It is July 1998.
The new electricity markets, the ISO and PX have been operating rather well considering they have only been in place for six months. Several large well-financed project developer consortiums have formed and are proposing to enter the California market in a major way. Each includes an established utility/plant operator, turbine manufacturer, gas supplier and construction firm.

While a majority of the smaller firms are taking a wait-and-see approach to California's restructuring, a few of these large consortiums have taken a very aggressive approach toward constructing new plants or purchasing and repowering existing generation. Their business strategy is to get a jump on the competition and become a major player early, thereby discouraging other potential competitors from entering the market.

These large project development consortiums have been successful, to a limited degree, at securing up-front "anchor" tenants. Two distinct strategies have emerged. One strategy is to secure "anchor tenants" from within existing municipal district and irrigation districts, expansion of district service territory through annexations, creation of new muni or irrigation districts, muni-lite and other creative approaches to municipalization.[5] Many issues and problems arise from this strategy. However, since municipal and irrigation district electric loads are not subject to the IOU based CTC, it is an effective way around the CTC.

The second strategy successfully employed by project developer consortiums in bypassing the CTC include serving <u>brand new</u> loads, load growth,[6] and customers with interruptable service[7]. Since this strategy requires direct access contracts between the generator and end user, large industrial and commercial customers with self-generation or cogeneration opportunities are targeted by project developers.

With a robust economy, rising growth rates and increasing demand, coupled with an aging, inefficient generation system, these project developers forecast a bright future and acceptable rates of return on their investment with reasonable amounts of risk.

Energy Facility Ramifications:
During the time period 1996-2000, 4-5 major power plant proposals are assumed. The projects will range in size from 25-400 MWs and will most likely be gas-fired. Additionally 2-3 existing units may be repowered and up-sized depending on the timing of divestiture decisions.

Scenario #2--Regulatory Uncertainty or "Let's Wait and See"

☞ **Driving Force/Scenario Theme:** Regulatory Uncertainty and an Over Supply of Capacity

Scenario presumptions:

- Regulatory uncertainty continues throughout this period
- Complexities of implementing ISO and PX are sizable
- Computer bids for ISO control center have hit numerous snags
- Restructuring EIR taking longer than anticipated
- Scope and adequacy of the EIR is challenged in the courts
- Restructuring delayed for two years
- Project developers, Munis, IOUs and financial community are reluctant to move forward with any large projects and take a wait-and-see approach
- Increased out-of-state purchases, declining reserve margins and uncommitted DSM fill the shortfall in supply and demand
- Scenario assumes few, if any, new power plant or transmission projects

It is April 1997.
January 1, 1998, the date to implement restructuring, is fast approaching. The complexities of organizing and implementing the ISO and the PX are overwhelming. The process is grinding on ever so slowly and the parties are getting bogged down in a sea of details. Bids for the software and hardware for the ISO control center have run into numerous snags which have caused unplanned delays to the timetable.

The electric industry restructuring Environmental Impact Report (EIR) is taking longer than anticipated. Parties in the CPUC restructuring process, not pleased with the restructuring decisions of the CPUC and other impacted groups not involved in the CPUC process, heretofore, are using the EIR to gain concessions and are attempting to delay the implementation of restructuring. These same groups have mounted formidable challenges as to the scope and adequacy of the EIR in the courts. These cases are substantial and could drag on for months, if not years, before being resolved.

It is apparent that restructuring will not be implemented by January 1, 1998 as originally planned. The CPUC delays the implementation date to January 1, 1999 and then must grant a second delay to January 1, 2000.

Uncertainty is driving the decisions, or more appropriately the indecision, of the utilities, project developers and the financial community. Uncertainty resulting from these massive changes and the lack of clearly defined federal and state laws, rules and regulations leave project developers, investor-owned utilities and municipal utilities with few short-term options in the new market. Considerable concern continues to persist over wholesale and retail access to transmission and distribution grids; the ISO and PX and how these business units will be organized, financed and operated; the Environmental Impact Report; and the size and magnitude of the various access and transition charges. This continued uncertainty has made it almost impossible for project developers to create and implement a business plan to take advantage of the slowly emerging electricity markets in California and the west.

The earlier rulings of the CPUC affecting the potential stranded investments of investor-owned utilities have convinced many independent power project developers that the short-term generation market will continue to be dominated by the investor-owned utilities. The CPUC decision to protect the stockholders during the transition by using a universal competitive transition charge (CTC) paid by all ratepayers will leave the utilities in a very strong market position.

This regulatory uncertainty makes it even more difficult for small project developers with limited financial assets to assume the risks and make business decisions regarding the market values of divested utility generation plants and to decide whether to bid on plants and assume the risk that a viable market will emerge in the next five to ten years. Most project developers agree that the emerging market will be dominated by large corporations with strong financial backing. This kind of organization and capital will be necessary to compete with the market power of the investor owned utilities in California. The limited market for new or repowered generation projects will probably be financed on the balance sheets of large corporations. The risks appear to be too great at this time to attract investment bankers and financial institutions to newly emerging electricity markets.

Energy Facility Ramifications:
The "Let's Wait and See" scenario presumes that regulatory uncertainty, coupled with a short-term surplus of competitively priced out-of-state supplies, adequate transmission capacity, relatively high reserve margins and a high CTC leave few incentives for project proponents to construct new generation or repower existing units through the year 2003. Regardless of the delays in the start up of the ISO and PX, the outcome of this scenario is the same--an over supply of cheap power results in little if no appetite for new plants. Few, if any, new generation or transmission projects are anticipated under this scenario.

SCENARIOS FOR THE SIX- TO TWELVE-YEAR PLANNING PERIOD: 2001-2007

The range of scenarios possible for the six- to twelve-year planning period is enormous. There are significant uncertainties related to the assumptions associated with restructuring, the decisions that will made by the regulatory and legislative decision-makers, possible legal actions and then the reality of implementation. However, in developing the four scenarios for this time period, we assumed that the industry in general would be moving from a period of regulatory uncertainty to one of certainty. We also assumed that the demand and supply gap would continue to grow due to increasing population and increasing use of electric vehicles and other electro-technologies. Out-of-state purchases, uncommitted DSM (staff's middle-level) and declining reserve margins from 18-22% to the WSCC guideline level of 7% will only partially fill the gap in supply and demand. The CTC will remain in effect through 2003 and once amortized, nuclear generation will be cost effective in the market as long as no major repairs, such as to steam generators, are required. This scenario assumes that PG&E and SCE will divest about 50% of their fossil generation assets as the CPUC is urging and retain generation units with strategic locational market power as required by the CPUC.

Scenario #3--Repowering or "Utilities Strategic Advantage"

☞ **Driving Force/Scenario Theme:** Utilities Desire to Retain Market Shares and Market Power

Scenario Presumptions:

- Utilities spin-off certain plants to their subsidiaries which then become independent through stock transfers[8]
- Utilities retain units with strategic locational market power as required by the CPUC[9]
- Utilities sell a few plants outright to competitors
- Utilities pay close attention to maintenance schedules and accepted maintenance standards resulting in reduced generation availability
- The resulting reduced generation availability allows the utilities to game the pool prices to their benefit as well as to their former subsidiaries
- The spin-off provides the utilities' former subsidiaries a head start and sizeable market shares
- Scenario assumes 2-3,000 MW of repowered up-sizing to meet load growth

The year is 2001.
The CPUC forced divestiture of utility-owned generation is in progress. The utilities have acquiesced to the CPUC and have agreed to "voluntarily" divest 50% of their generation (retaining those units with locational market power) but in return received concessions from the CPUC that they (utilities) would be able to select which plants to sell and which to spin-off to independent companies. This was a hard fought compromise by all parties involved. The utilities had challenged the CPUC's authority to require divesture on constitutional grounds and the CPUC was especially concerned over the utilities standing in the courts on this matter. In a move to minimize objections and reduce the "political heat", the utilities reluctantly agree to sell a limited number of their existing generation units to their competitors.

The market value estimates for the soon to be divested generation units hit rock bottom. The over supply of economical energy, the exceptionally low PX market prices driven down by the CTC and environmental site remediation risks (ground water and soil contamination from many years of use of oil, solvents, cleaning agents, compounds containing heavy metals and other toxics) are all contributing to a depressed market for these plants.

There are also concerns that selling such a large number of units and megawatts (50% of SCE and PG&E fossil-fueled generation) will overwhelm the demand to purchase these units pushing prices further downward. This concern is validated by "independent" studies completed by Goldman and Sachs for PG&E and other studies from SCE. Armed with this rationale, utilities move swiftly to divest the remaining 50% of their generation by spinning off most of these units to their unregulated subsidiaries. Value is determined by an "independent" party such as Goldman and Sachs and approved by the CPUC.

To minimize objections to the spin-off, PG&E and SCE agree to sell a limited number of plants in the market after their spin-offs have been completed and approved by the CPUC. The limited number of plants that the IOUs decide to sell engender acute competition among project developers hungry to get a foothold in the California market.

The utilities and their former subsidiaries continue to enjoy market dominance. The regulated utilities begin to experiment with different operating regimes and planned maintenance and outage schedules, adhering closely to industry standards for maintenance and repairs. With the utilities continuing to dominate the supply market[10], they will be able to experiment with various supply bidding strategies in an effort to maximize the market clearing price to the benefit of their regulated plants and the plants spun-off.[11] Even the purchases of the few utility plants auctioned off are benefited.

The gaming of supply prices continues as long as the utilities hold a dominate position in the market. The spin-off gives the newly independent generating companies a considerable head start in the generation market. Considering that the planning, permitting, financing and construction of a utility-sized plant can take 5 to 8 years, this is a decided advantage.

Rates do not drop but remain high. Some shifting of costs among customer classes takes place. Residential classes are hurt.

Energy Facility Ramifications:

Scenario 3 is assumed to induce a number of repowers of existing plants by the utilities, the newly independent generating companies and project developers who purchased utility plants. Plants will be repowered and up-sized. About 2-3,000 MW of additional generation is assumed under this scenario to meet load growth. Repowering and up-sizing may require some upgrades to existing transmission depending upon on the amount of the up-sizing and the ability of the transmission system to take additional generation.

Scenario #4--Distributed Generation or "The Demise of Electricity as a Commercial Commodity"

☛ **Driving Force or Scenario Theme:** Distributed Generation New Technologies

Scenario Presumptions:

- Rates do not drop but remain high. Some shifting of costs among customer classes takes place. Residential classes are impacted
- New technologies become cost effective--natural gas fuel cells, micro-sized turbine generators, flywheels and PVs
- Utilities install and maintain substation-, industrial-, commercial-sized distributed generation units
- Reliable natural gas cogenerating home-sized appliances are readily available and can be purchased with a credit card
- Utilities install and maintain home-sized, "Mr. Cogen" units
- The distributed generation strategy undermines the buyers of the utility plants
- Scenario assumes hundreds of commercial-, industrial-, substation-sized units and thousands of home-sized distributed generation units accounting for about 10 % of total statewide demand (6,500 MW)

The year is 2001.
The new competitive regime is now at least three years old. Time-of-use meters with remote telemetry access are readily available. The utilities have completed the forced divestiture of most of their load-following resources retaining only those units which have locational market power. Little new generation has been built because of the large amount of excess capacity supported by the CTC[12] and the large amount of out-of-state generation supplying the California market. Easy municipalization also known as "muni-lite" has been stopped by the Federal Energy Regulatory Commission's strict interpretation of the National Energy Policy Act's "sham" transaction clause when granting wholesale transmission access.

Large users of electricity are receiving most of the benefits of restructuring. Their large, steady loads make them very attractive customers for both the utility distribution companies (UDCs) and marketeers. Variable energy costs are low for most customers, but total costs for small electricity consumers remain high. The fees California electricity customers must pay to access the distribution and transmission system, support the ISO and PX, support public goods research and development, and keep expensive renewables in the market are pushing other solutions to the question of how to avoid all these charges.[13]

Then comes the technological breakthrough in distributed generation: the first reliable cogenerating home appliance using natural gas that can be purchased with a credit card and installed in less than a month. The natural gas production companies and various "resellers" seek to aggregate households and businesses into distributed utilities (DUs) with powerplants, load shifting and process heat requirements. These distributed utilities will incorporate just enough photo-voltaic generation with storage to clear the minimum renewable energy purchase requirements. They may even sell some to the UDCs. The name of the game will be to avoid, rebate, credit and play the system so as to minimize the payments to the system and maximize savings[14] to the customer.

The UDCs, fearing that they could become "wires only" companies forever and sensing an opportunity to reenter the generation business without risking large amounts of capital over many years building large powerplants, begin to install and maintain industrial-sized and commercial-sized distributed generation units to keep from losing large customers. In addition they seek out the natural gas local distribution company with joint-venture offers to purchase large numbers of "Mr. Cogen," install them and maintain their home-sized units. Distributed generation may also provide a way to undermine the market position of those entities that purchased their "crown jewels"[15] during the UDCs' forced divestiture of fossil-fired powerplants.

A Look into the Future, One of Many Possibilities--The system's fixed charges remain high but fewer customers are willing to pay them. In a move to lower their costs, the UDCs attempt to break their QF contracts and reduce their participation in PX. The CPUC accommodates them by abolishing the concept of long-run avoided cost and defining short-run avoided cost in terms of the month-ahead electricity contract prices by geographical region in the New York Mercantile Exchange's electricity futures market. The Legislature reduces the surcharges for renewables, DSM and RD&D in order to reduce the total cost of electricity, but it is a case of too little, too late. The ISO downsizes and reduces its overhead. Even smaller customers no longer need to purchase most of their electricity from the UDCs and/or PX. Fewer and smaller transactions take place in PX. Eventually it closes and its remaining functions are merged with the ISO.

A Look into the Very Distant Future--The reproducibility and modularity of distributed generation technologies means generators are no longer brought into being by project developers, but by manufacturers and installation contractors. As scale decreases and locations proliferate, generation sales take the form of retail equipment sales and installations. When generation shrinks towards household scale, generation projects disappear to be replaced by home appliances. In the ultimate distributed generation world, which is technically feasible today although a long way off in reality, there are no utilities. There is no transmission, no central plant generation, no power pools and no independent system operator. Electricity does not even exist as a commercial commodity. Think of residential hot water as an analogy. Consumers do not purchase hot water, they purchase an appliance (hot water heater) and the fuel to run the appliance (natural gas or electricity) and produce hot water on site in the amounts needed. And so it may be with electricity, consumers will purchase an appliance and the fuel to run the appliance and produce electricity on site in the amounts needed.[16]

Energy Ramifications:
The distributed generation scenario is assumed to induce thousands of home appliance-sized generation and hundreds of substation-, neighborhood-, industrial- and commercial-sized generation sources. This could account for about 10% of statewide demand or about 6,500 MW.

Scenario #5--Unleashing the Entrepreneurial Spirit or "The Great CTC Escape"

☞ **Driving Force/Scenario Theme:** A Competitive Market Begins to Emerge

Summary of Scenario Presumptions:
This is similar to Scenario #1--Early Market Positioning where very large, well financed consortiums quickly jumped into the market. The difference is that smaller company's are also getting into the act and everyone is being very creative and are finding many new and unanticipated ways around the CTC.

- Assumed staff's declining uncommitted DSM case (low level)
- Costs of central plant sized turbines continue to drop
- The existing system continues to age and is unable to compete with new efficient technologies--plants are repowered or moth-balled
- Additional air quality changes require old plants to clean up air emissions, plants are repowered or closed
- San Onofre **or** Palo Verde nuclear plant become uneconomical as major repairs, such as to the steam generators, are required
- Diablo Canyon plant continues to operate as it provides valuable transmission and ancillary services to the grid due to its strategic location
- The CTC will become bypassable through creative strategies by customers, generators, and aggregators
- Project developers and aggregators contract with **new** loads, such as new communities, neighborhoods, government and schools buildings, shopping centers, subdivisions, office buildings, industrial parks
- Project developers will contract with large loads that currently have interruptable rates
- Scenario assumes 5,000+ MW of new gas-fired and renewable generation in the 25-400 MW range

The year is 2002.
The ISO and the PX have been in business for the past four years. The system's fixed charges, led by the CTC, remain high but more and more customers are not willing to pay them. Many creative ways have been found to bypass the CTC, heretofore, never imagined. There is an expansion of and more aggressive approach to the municipal and irrigation district strategies described in Scenario #1. There is a more sophisticated and thorough approach to new customers, load growth and interruptable service customers strategies of Scenario #1 as well. Not only are the very large customers (large industrial and commercial) benefiting, but medium sized and smaller customers are starting to benefit.

Much of the states new growth is targeted by non-CTC generators. Large master-planned developments and large subdivision are being targeted and served by aggregators and generation projects successfully bypassing the CTC. New shopping centers, industrial parks, office buildings and industrial facilities have been successful in avoiding the CTC along with current customers with interruptable service accounts.

One year later, 2003, Los Angeles, CA.
In a move, not surprising to industry insiders, SCE, SDG&E, Anaheim and Riverside jointly announce that they will close the two remaining units (Units 2 and 3--2150 MW) of the San Onofre nuclear power plant by the end of 2003 due to major repairs and persistent operation and maintenance problems encountered over the past several years.[17] Major capital investments for repairs forced the closure of the plant as it was no longer economical to operate and could not compete against newer natural gas and distributed generation technologies. With this closure and the earlier closure of Unit 1, the four utilities will close the complex and begin the decommissioning process (Either SONGS or Palo Verde could be closed if large capital costs for maintenance is required).

The generation system is aging and becoming more and more inefficient and polluting more in comparison with the new technologies of the day--2003 (more than 8,000 MW of existing generation is over 40 years of age). These old plants are no longer able to compete in the market. PG&E, SCE and SDG&E begin retiring their older, more costly plants as major repair costs are encountered and additional air quality retro-fit requirements are imposed.

Energy Facility Ramifications:
This scenario postulates up to 3,000 MW[18] of new or repowered generation, another 2,150 MW to replace San Onofre nuclear power plant and an undetermined amount to replace retired plants, of gas-fired and renewables in the 25-400 MW range, will be added between 2001 and 2007. New generation and repowering may require some upgrades to existing transmission depending upon on the location and amount of generation to be added and the ability of the transmission system to take additional capacity.

Scenario #6--The Market Blossoms or "Everything Works as Planned"

☛ **Driving Force/Scenario Theme:**CTC is Fixed Charge Thereby Reducing Variable Energy Costs

Scenario presumptions:
This scenario posits a "restructured" industry that works as well as the theorists hoped it would. The key assumptions are a rate design for the CTC that is efficient, complete divestiture of IOU in-state fossil **and hydro** units to many competitive companies, and QF standard offer contracts are bought out or voluntarily abrogated so that they can sell into the power exchange. The net result is maximum competition.

- CTC is levied as a fixed charge rather than a variable or a cents per kWh of usage as is described in the CPUC Restructuring Decision
- The marginal price of electricity falls.
- Low marginal rates induce economic development
- New industries and businesses relocate to California
- Staff's declining DSM forecast is assumed
- Utilities completely divest[19] themselves of their fossil and hydro units to many independent and competitive companies
- Increased consumption drives the competitive market
- Costs of turbines and emission control retrofits continue to drop
- SONGS **or** Palo Verde nuclear plant becomes uneconomical as major repairs to the steam generator is required
- Some older fossil generation plants are closed and replaced by new or repowered generation
- Diablo Canyon continues to operate and provide valuable transmission and ancillary services to the grid due to its strategic location
- Scenario assumes in 11,000+ MW of new generation--in-state, out-of-state and repowers

The year is 2001.
The ISO and the power exchange have been in business for the past three years. The CTC as implemented is not the design the original restructuring decision suggested.[20] Instead of being a cents per kilowatt-hour charge that penalized consumption, it is levied as a fixed charge per customer. The more a customer consumes, the lower the average cost per kilowatt-hour of that customer's bill. This encourages consumption. This pricing methodology also hurts the cost-effectiveness of DSM. Hence, there is a decline in the amount of DSM.

Rising demand and the complete divestiture of all in-state fossil and hydro generation to 40+ companies insures a very competitive market. Power exchange prices fall as competitors cut their expenses to the bone and make their profits on volume. This encourages more consumption. The over-capacity situation begins to disappear before the end of the transition period.

One year later, 2002, Los Angeles. In a move, not surprising to industry insiders, SCE, SDG&E, Anahiem and Riverside jointly announce that they will close the two remaining units (Units 2 and 3--2150 MW) of the San Onofre nuclear power plant by the end of 2003 due to major repairs and persistent operation and maintenance problems encountered over the past several years. Major capital investments for repairs forced the closure of the plant as it was no longer economical to operate and could not compete against newer natural gas and distributed generation technologies. With this closure and the earlier closure of Unit 1, the four utilities will close the complex and begin the decommissioning process (as in Scenario 5, SONGS or Palo Verde could be closed).

Repowering and re-using existing sites based on increasing demand begin even before the CTC expires in 2003.

Energy Facility Ramification:
Scenario 6 is assumed to induce 11,000+ MW of new in-state, new out-of-state and repowering generation to cover projected load growth (about 7,000 MW), economic induced load growth (about 2,000 MW) and another 2000+ to replace SONGS nuclear plant will be added between 2001 and 2007.[21] It is unclear how much will come from new in-state, new out-of-state and repowering.

SITING ISSUES AND CONSEQUENCES

A number of siting and environmental issues and consequences have been identified from the scenarios analysis (see Table 3). These are very preliminary but may represent the type of issues encountered in the future under restructuring. We plan to continue to identify and study these potential issues:

Lack of Market Rules--In the near-term, the lack of fully developed and understood federal and state rules governing transmission access, transmission rates, CTC, the ISO and PX may dampen project developers and financiers interest in developing new projects in California.

Transmission Lines--New additions and/or upgrades to the transmission system may result if significant amounts of new in-state generation (scenario #6 and possibly #5) is not located near load centers. Environmental constraints may make it increasingly more difficult to site new generation near the load centers.

Price and Availability of Air Quality Offsets--As significant numbers of power plants are proposed and built, the cost and availability of offsets may become more uncertain. The lack of economically priced emission offsets to support the significant amounts of new generation, as described in scenarios #5 and #6, may be problematic, especially near load centers where the availability of air quality offsets may be the most acute.

Air Quality (Distributed Generation)--Under the distributed generation scenario, air quality may be degraded depending on the technology employed. Fuel cells and PVs would be cleaner than current central plant generation. Based on today's technology, very small natural gas combustion turbine emission levels are greater than current utility-scale combined cycle projects. However, future technology breakthroughs may result in combustion turbines that are much cleaner than they are today and comparable with utility-scale projects.

New Generation Facilities--Where a significant number of new power plants (Scenario #5 and #6) and associated facilities such as roads, transmission lines and pipelines for water and/or fuel are necessary, site specific environmental issues may constrain siting options. Significant costs could be associated with resolving issues related to adverse effects on endangered species, land uses, prime agricultural land, water resources, visual impacts, and, on public health (such as concerns over air emissions and electromagnetic fields).

Desalination, Biomass and MSW--A significant number of new and repowered power plants could play an increasingly important part in solving the growing problems in California associated with biomass and municipal solid waste disposal. They may also play an important role in providing desalinated water, primarily in water-short coastal areas. However, to the extent that these facilities cannot compete in the market, energy solutions to social and environmental problems may be lost. These facilities could also result in concerns over endangered species, incompatible land uses, prime agricultural land, water resources and public health.

Toxic Clean-Up of Sites--Past use of oil, solvents, cleaning agents, compounds containing heavy metals and other toxics at existing electric generation sites may require extensive clean-up of ground water and soils prior to repowering.

Water Resources--Existing power plants, particularly those that employ once-through cooling, may encounter potential water quality and water use issues unless improved water processing and cooling techniques are incorporated in the design of the repowered plant. These designs can enable the new facility to meet existing and future water standards.

Land-Use Conflicts (Repowering) --Development of new communities and expanded older communities built near existing generation plants, combined with increased community awareness and concerns may lead to incompatible land uses and noise problems, if an existing plant is considered for repowering. Some communities may expect that certain existing plants will be retired and removed at the end of their design life.

Land-Use Conflicts (Distributed Generation)--Depending upon the distributed generation technology employed, incompatible land uses and noise problems may arise, unless measures are taken in the design of the site and facilities to mitigate the potential issue.

Environmental Justice - Repowering existing power plants or the addition of new power plants and related facilities to areas already experiencing environmental impacts may become an issue. Environmental justice as an issue may arise if a disproportionate share of pollution occurs in a populated area and newly refurbished or proposed facilities add to a real or perceived problem.

Modify Local Building and Fire Codes--Local building codes and Fire and Safety codes may need to be modified to accommodate distributed generation units within industrial, commercial and residential buildings. Underwriters Laboratories (UL) certification will be needed for smaller appliance-sized distributed generation units.

Product Standardization--The distributed generation industry will need to standardize products and interconnection requirements for the various sizes of distributed generation units and the loads they will be serving.

Table 3--Comparison of Issues and Consequences by Scenario

ISSUES/CONSEQUENCES	#1	#2	#3	#4	#5	#6
Lack of Market Rules	x	x				
Transmission Lines					x	x
Price & Availability of Air Quality Offsets					x	x
Air Quality (Distributed Generation)				x		
New Generation Facilities					x	x
Desalination, Biomass and MSW					x	x
Environmental Justice			x		x	x
Toxic Clean-up of Site	x		x		x	x
Water Resources	x		x		x	x
Land-Use Conflicts (Repowering)	x		x		x	x
Land-Use Conflicts (Distributed Generation)				x		
Modify Local Building and Fire and Safety Codes				x		
Product Standardization				x		

CONCLUSIONS AND RECOMMENDATION:

Change will characterize the electricity industry over the next several years. The results of this change are expected to create a more competitive industry, reduce electricity prices and provide choice for consumers. However, as with any change, there are uncertainties. In responding to the **ER 96** Committee's request for information on trends in energy facilities in California, current uncertainties did not point to any one trend but rather a number of possible trends with differing implications and outcomes. Consequently the staff used scenarios to describe possible futures under restructuring. These were subsequently used to identify the resulting energy facilities and siting issues and determine if any common conclusions or recommendations could be drawn. In presenting this analysis, we are not advocating any scenario nor do we feel they are the only scenarios possible.

The scenarios provide different views of the future. At one end of the spectrum Scenario 1, and to a greater extent Scenarios 5 and 6, foresee a robust economy and increasing market competition with increasing market penetration of new generation and repowered plants beginning with restructuring in 1998 and picking up momentum with the ending of the CTC around 2003. The other end of the spectrum, Scenario 2, there are few, if any, new generation or repowering projects proposed through 2003 when the CTC expires.

To more fully complete the picture, Scenario 3 foresees a future of repowering activities in-lieu of new generation due to the strategic location of the repowered plants and the utilities desire to retain market shares. And lastly, with new technologies driving the future, Scenario 4 foresees a future of rapidly expanding cost-competitive distributed generation units from 5 MW down to 4 kW to serve industrial-, commercial-, and household-sized applications.

Each story or scenario has a corresponding set of issues and future outcomes. Decisions being debated by the CPUC, FERC and the state legislature will have major ramifications for the future of the electric utility industry, project developers, utility stock holders and ratepayer. These stories help us to anticipate these changes and to be prepared to respond to a wide range of future issues and events which, if unanticipated, could adversely affect the efficient and timely permitting of energy facilities for California.

In light of the great deal of uncertainty surrounding restructuring, the multiplicity of decisions that must be made and their far-reaching impacts on the public, we recommend that with respect to trends in the location, size and type of new generation and transmission lines, that we continue to monitor the process and to provide information to the public, the legislature, and other decision makers as appropriate. To accomplish this, **we recommend a continuation of the Energy Facilities Siting Division's, Trends and Issues Program as a useful approach to gathering information, identifying key trends and issues, and developing policy recommendations regarding the various scenarios analyzed (see Executive Summary).**

ENDNOTES:

1. Peter Schwartz, **The Art of the Long View, Planning for the Future in an Uncertain World,** Doubleday Currency, New York, NY, 1991, page 3-4.

2. We have avoided the more traditional approach of providing ELFIN modeling runs, resource accounting tables, estimates of uncommitted DSM, demand, supply and need projections. However, these projections are valuable pieces of information and were used as a point of reference in developing the six scenarios.

3. Source: **ER-94 Appendices**

4. In a staff revised report on: **Uncommitted Energy Efficiency Forecasts** , May 17, 1996, Preliminary Testimony for the June 11th, 1996 **ER 96** Committee Hearing, CEC staff developed and analyzed three scenarios for levels of uncommitted DSM. The three scenarios are entitled "Declining Energy Efficiency" (low), "Business as Usual with Spillover Effects" (middle), and

"Restored Funding with Spillover Effects" (high). The middle case is about the same as ER 94 forecasted uncommitted DSM.

5. For a detailed discussion of municipalization strategies see a CEC staff report on, **Municipal Utilities strategies to Deal with Restructuring and Competition**, prepared for the June 11, 1996 ER 96 Committee Hearing, Linda Kelly and Ruben Tavares, May 14, 1996.

6. It is unclear how the CTC will be actually implemented by the CPUC, however, it is assumed that new loads and new customers will be able to bypass the CTC provided they take delivery as a wholesale customer (FERC regulated) rather than as a retail customer (CPUC regulated). The May 1996, **Assigned Commissioner's Ruling**, signed by CPUC Commissioner P. Gregory Conlon seems to support this interpretation and is quoted here--"Generation is to be priced by the market, transmission rates are to be set by FERC, and distribution rates are to be set by this Commission. The Policy Decision intends that these costs be collected through a non-bypassable competition transition charge for all retail customers, ..."

FERC's definition of stranded costs and their collection methods are also different than the CPUC's--FERC Order No. 888, pages 477-600.

It has also been argued that new customers should be exempt from the CTC as the calculation of the CTC is based on existing generation that was built to serve existing loads. Therefore, new loads never before on the system should not pay the CTC.

7. In Edison's service area there are about 800-1,000 large industrial and commercial customers with interruptable service.

8. PG&E and SCE would have to pay capital gains taxes in an outright sale of generation assets. Payment of capital gains taxes would reduce the amount available to contribute towards lowering the CTC. Capital gains can be avoided with a spin-off of assets to an independent company.

9. Utility plants that are deemed to have strategic market power due to their location with respect to the transmission system will be retained by the utilities and be included in the utilities performance based ratemaking regulated by the CPUC.

10. As an example SCE's baseload capacity of 5,278 MW coupled with their instate load-following fossil units is equal to approximately 71-79% of Edison's total forecasted system peak demand for the years 1998-2003. If Qualifying Facilities and existing contractual relationships such as the BPA exchange are counted, Edison could easily provide the "marginal" unit in its largest PX zone 100% of the time.

11. For a discussion of various power pool gaming strategies see: **Comments of the California Energy Commission in Response to the March 19, 1996 Filings of Southern California Edison Company and Pacific Gas and Electric Company, re: Voluntary Divestiture Plans**, Attachment #1, <u>A Staff Report On: Generation Market Power in Electricity Restructuring</u>, p 18.

12. The Competition Transition Charge will support the above-market costs of existing utility generation resources through 2003 and qualifying facility power purchase agreements for the term of those agreements at least through 2015.

13. It is assumed that like the CTC, all these extra charges will be charged as percentages on the dollar amount of the customer's bill for the following reasons: (1) the CTC is described as a variable charge in the California Public Utilities Commission's 12/20/95 decision on restructuring (page 141) and (2) fixed charges (based on some measure of kilowatts rather than kilowatt-hours) would put demand-side management at an even greater disadvantage in the competitive market.

14. The distributed utilities might apply for research and development surcharge funds and credit some of those monies to their distributed generation "partners" who participate in distributed utility-sponsored R&D programs effectively rebating that fee to participants.

15. The utilities existing gas-fired powerplants had the most valuable attribute in the competitive market: Location, location, and location. Because of their load-center locations these existing powerplants could literally not be duplicated. Now distributed generation can be sited in the same place making them eligible to compete for ancillary services and power sales in the same zonal markets.

16. Condensed and paraphrased from Michael Margolick's paper titled, **Sustainability, Technology and Utility Reform**, presented at the Seventh Annual Canadian Independent Power Conference and Trade Show, Toronto, Ontario, December 12-13, 1995, Michael Margolick, Ph.D., The ARA Consulting Group Inc., Vancouver, B.C.

17. By the end of 2003, San Onofre Nuclear Power Plant will have been fully amortized through the CTC.

18. An annual load growth of about 1.8% equates to 1,000 MW per year or 7,000 MW over this seven year period. In Scenario 5, it is assumed that between 40-50% of load growth (larger industrial and commercial loads) will be prime customers for CTC bypass.

19. Complete divestiture of utility in-state fossil and hydro units is not a part of the current restructuring decision or the utility filings on market power. Only PG&E and SCE have been urged by the CPUC to voluntarily divest 50% of their fossil units. However, the fewer units divested to independent, competitive entities, the less competition and the thinner the market. PG&E has expressed a willingness to divest 50% of its in-state fossil units and a willingness to explore the divestiture of other units. SCE is willing to voluntarily divest 50% of its in-state fossil units or about 5,000 MW. Both utilities impose many conditions on their divestiture agreements. SDG&E was not required by the CPUC to file a divestiture plan and has made no statements that we know of regarding divestiture.

20. This scenario requires a CTC that sends efficient pricing signals. Since most of the costs that the CTC is to pay off are sunk and fixed, a CTC should be a fixed charge on the customer's bill. However, on page 141 of the 12/20/95 CPUC restructuring decision the majority writes: "The CTC will be a percentage surcharge on the dollar amount of each bill of each customer...."

Therefore, as it stands now the CTC will not be a fixed charge on the customer's bill but rather a variable charge. Such a CTC will increase prices, reduce consumption and distort market choices. A CTC charge is intrinsically a backward looking mitigation of past mistakes. Collecting a CTC in a way that distorts relative energy prices results in investment mistakes. If the power exchange generation price really does average $0.05/kwh, increasing people's energy charge to $0.07/kwh and motivating them to think about DSM and distributed generation is economically inefficient. The concept of a surcharge on top of all other charges is economically unsound, and would lead to another round of bad investment decisions for society.

21. An annual load growth of about 1.8% equates to 1,000 MW per year or 7,000 MW over this seven year period. In Scenario #6, it is assumed that an extra 2,000 MW of demand is the result of efficient pricing signals of fixed charge CTC.